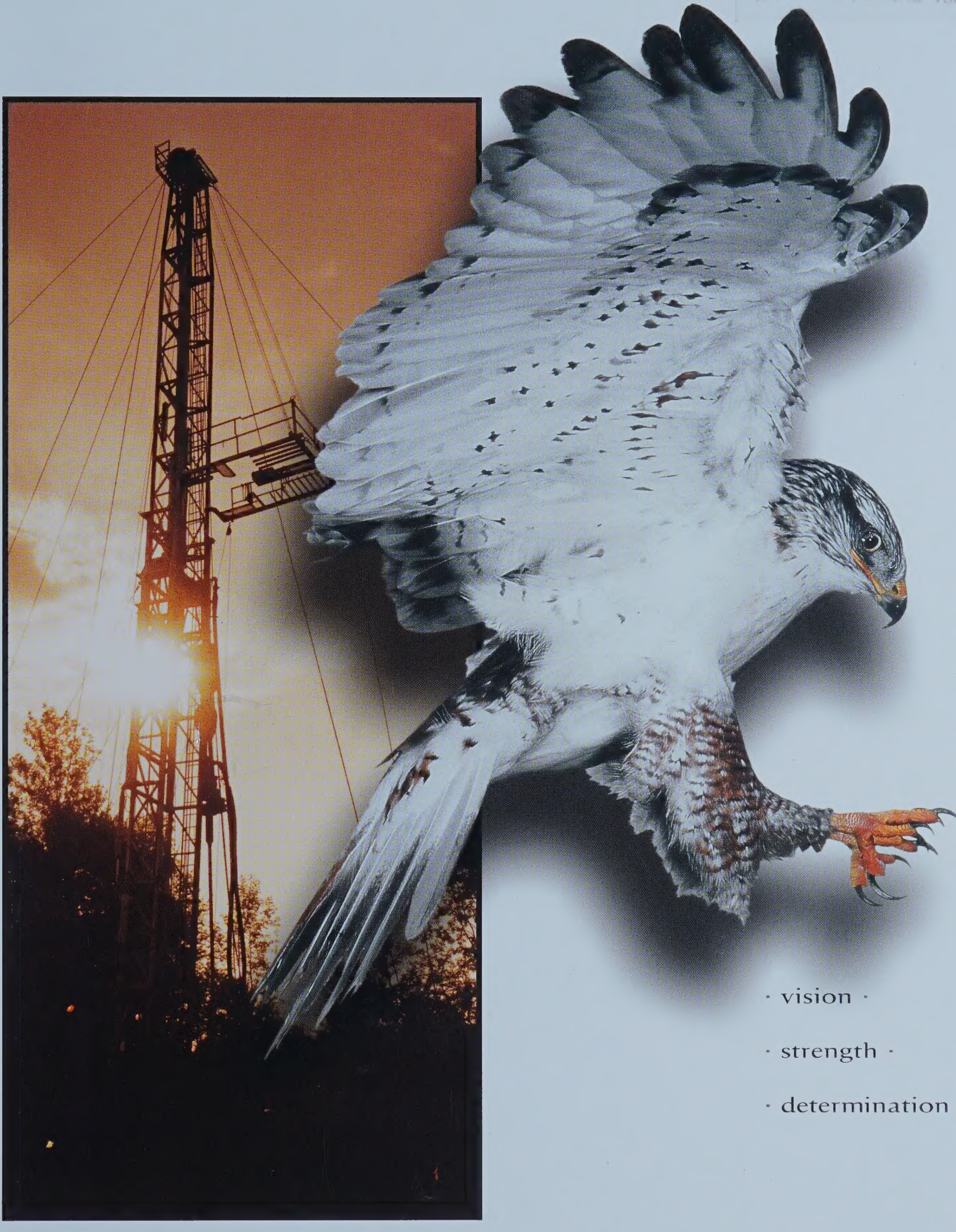

· vision ·

· strength ·

· determination ·

Hawk Energy Corp.

2003 Annual Report

Annual General Meeting

The annual meeting of the shareholders of Hawk Energy Corp. will be held in the Boardroom of the legal firm of McCarthy Tétrault LLP, at Suite 3300, 421- 7th Avenue S.W. Calgary, Alberta on June 10, 2004 at 3:00 p.m.

· vision · strength · determination ·

Corporate Profile

Hawk Energy Corp. is a growth-oriented junior resource company engaged in the exploration, development and acquisition of oil and natural gas properties in Alberta and Saskatchewan. The Company's common shares are listed for trading on the TSX Venture Exchange under the trading symbols "HK.A" and "HK.B".

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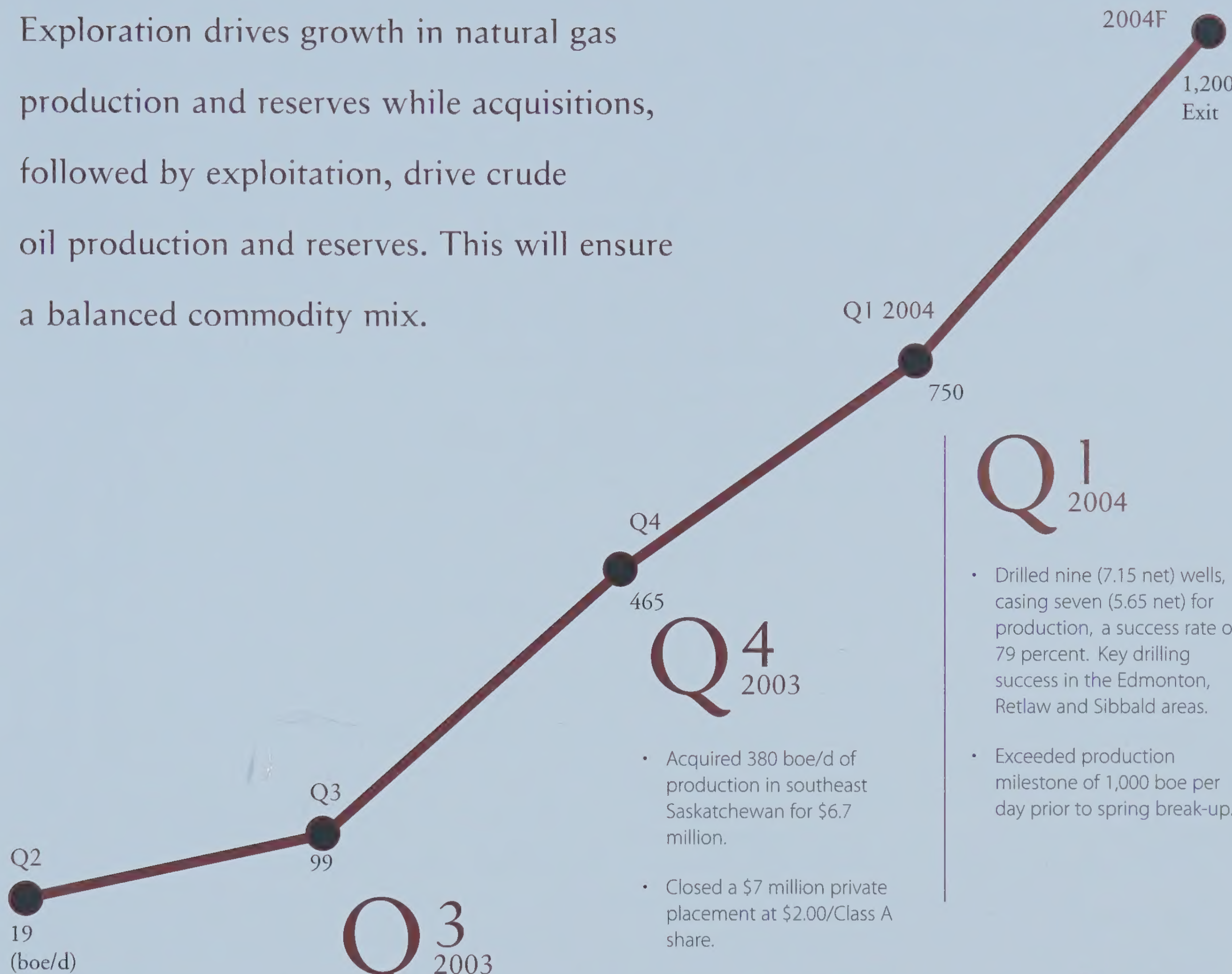
IBC. Shareholder Information

Exploration drives growth in natural gas production and reserves while acquisitions, followed by exploitation, drive crude oil production and reserves. This will ensure a balanced commodity mix.



Q2 2003

- Completed initial public offering on June 5 for gross proceeds of $9.25 million.
- Assembled a team of highly skilled professionals.
- Drilled two (1.42 net) wells with 100 percent success.

Q3 2003

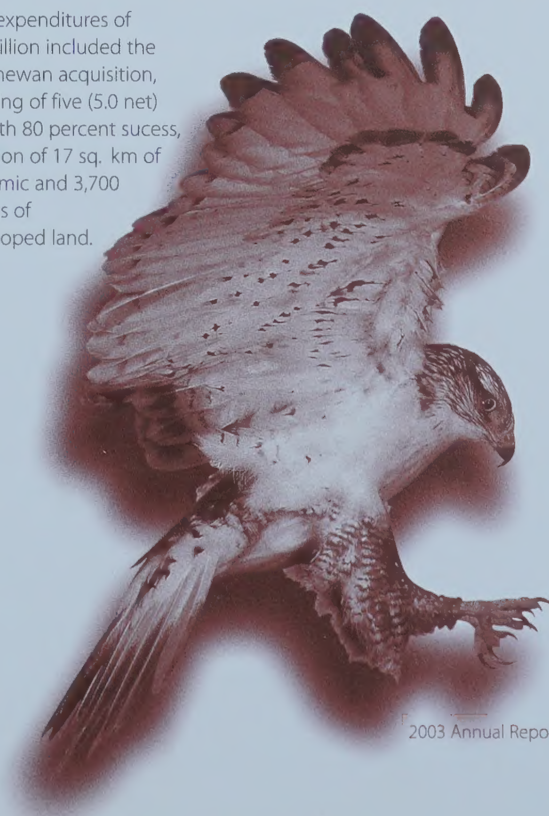
- Incurred capital expenditures of $2.3 million.
- Drilled seven (5.9 net) wells with 86 percent success.
- Acquired 3,000 net acres of undeveloped land.
- Acquired 159 km of 2-D seismic over prospects in core areas.

Q4 2003

- Acquired 380 boe/d of production in southeast Saskatchewan for $6.7 million.
- Closed a $7 million private placement at $2.00/Class A share.
- Capital expenditures of $10.4 million included the Saskatchewan acquisition, the drilling of five (5.0 net) wells with 80 percent sucess, acquisition of 17 sq. km of 3-D seismic and 3,700 net acres of undeveloped land.

Q1 2004

- Drilled nine (7.15 net) wells, casing seven (5.65 net) for production, a success rate of 79 percent. Key drilling success in the Edmonton, Retlaw and Sibbald areas.
- Exceeded production milestone of 1,000 boe per day prior to spring break-up.



2003 Results

Financial ($000s, except per share data)	2003 Q1	Q2	Q3	Q4
Revenue, net of royalties	–	66	264	1,183
Cash flow from operations	(11)	(24)	118	475
Per share basic	–	–	0.02	0.07
Per share diluted	–	–	0.02	0.06
Net income	(11)	(25)	41	(18)
Per share basic	–	–	0.01	–
Per share diluted	–	–	0.01	–
Working capital	876	8,712	6,571	3,182
Capital expenditures	113	498	2,259	10,263
Long-term debt	–	–	–	–
Shareholders' equity	989	5,979	6,020	12,830
Shares outstanding				
Class A	4,000,000	7,700,000	7,700,000	11,200,000
Class B	–	832,500	832,500	832,500
Options	–	770,000	770,000	770,000
Weighted shares outstanding				
Class A	2,666,667	2,839,394	4,579,377	5,487,966
Class B	–	126,136	378,998	498,546
Options	–	606,667	629,635	659,344

Operating

Production				
Crude oil & NGLs (bbls/d)	–	16	76	283
Natural gas (mcf/d)	–	18	141	1,091
Combined oil equivalent (boe/d)	–	19	99	465
Average sales price				
Crude oil ($/bbl)	–	29.08	26.48	32.13
Natural gas ($/mcf)	–	5.62	4.90	5.05
Combined oil equivalent ($/boe)	–	29.90	28.15	31.40
Wells drilled (gross)	–	2	7	5
Working interest proved reserves at Dec. 31, 2003				
Crude oil & NGLs (mbbls)				1,374
Natural gas (mmcf)				4,677
Total oil equivalent (mboe)				2,154
Working interest proved plus probable reserves at Dec. 31, 2003				
Crude oil & NGLs (mbbls)				1,684
Natural gas (mmcf)				5,742
Total oil equivalent (mboe)				2,641

It gives me great pleasure to present the shareholders of Hawk Energy Corp. with the Company's first annual report. In June 2003, Hawk became a public oil and natural gas company. Since then Hawk has experienced rapid growth. Over the past year, the Company has accomplished the following:

- Assembled a talented team of highly skilled professionals;
- Completed Hawk's initial public equity offering, raising gross proceeds of $9.25 million;
- Drilled 14 (12.3 net) wells, 71 percent of which were classified as exploration wells, resulting in 12 (10.3 net) producers for an overall success rate of 86 percent;
- Acquired properties producing 380 barrels of oil equivalent (boe) per day of light oil in Southeast Saskatchewan for $6.7 million;
- Completed a second equity offering of $7.0 million;
- Incurred an average finding and development cost of only $6.72 per boe of proved reserves added;
- Generated cash flow of $557,998 ($0.08 per Class A and B share) for the year; and
- Exited the year with production of 750 boe per day.

Average Production
(boe/d)

Growth Strategy

Hawk's growth strategy was formulated and refined at Hawk Oil Inc. This successful A/B-structured company, which was founded and managed by the current management team at Hawk Energy, was sold in February, 2003 to a Canadian energy trust for $50 million or $4.80 per share. The sale provided Hawk Oil's original shareholders an after-tax return of 350 percent over five years.

The basic growth strategy for both companies was and is to profitably grow the Company on a per share basis by focusing on cash flow. We accomplish this by targeting high-netback products in low-cost areas. These areas are characterized by year-round access, available existing infrastructure, moderate drilling depths, affordable land costs and in-house technical knowledge.

·Vision·

Our prior experience managing a junior exploration company gives us insight into areas where we can grow through a full-cycle exploration strategy. Our technical skills, combined with 2-D and 3-D seismic, have led to success at high-grading opportunities and reducing risk.

To achieve profitable growth, Hawk strives to be a low-cost producer, both in terms of finding and development costs as well as operating costs. Hawk ensures that its finding and development costs are among the lowest in the industry by maintaining strict control over the quality of the technical work that goes into a prospect as well as the capital incurred to transform the prospect into a producer. To ensure Hawk has the required control, we operate nearly every well we drill as well as the vast majority of our production. In addition, Hawk reduces operating costs to the greatest extent possible. In doing so, the Company maximizes cash flow that can be reinvested.

From left:
Erik DeWiel, VP Land and Corporate Secretary; Dave Bonnar, VP Corporate Development;
Steve Fitzmaurice, President and CEO; and Randy Deobald, VP Exploration

·Strength·

Our strengths include technical skills relevant to every aspect of our operations. These strengths allow us to control how we approach each prospect, the capital spent to bring production on stream and the ability to manage operating costs.

Risk mitigation is an important aspect of Hawk's strategy. The Company considers it prudent for a junior producer to pursue primarily moderate-risk, moderate-reward prospects. Accordingly, the Company has concentrated on moderate-risk areas such as Retlaw and Manitou Lake, resulting in an excellent drilling success rate accompanied by immediate cash flow. As Hawk continues its rapid growth, we will increase our exposure to higher-risk, higher-reward prospects.

The Company will also balance its drilling risk with solid acquisitions that offer exploitation opportunities. Hawk will seek to grow natural gas volumes predominantly through exploration and development drilling, while growing oil volumes predominantly through acquisitions followed by exploitation. Hawk believes this strategy will ensure a balanced commodity mix while avoiding the excessive prices currently being paid for natural gas-producing assets. Having said that, the Company will continue to be opportunity-driven in selecting prospects for either drilling or acquisition.

In order to maintain control over technical aspects, capital and operating costs, Hawk strives for operatorship and a high working interest in any development or moderate-risk exploration project. The Company continues to operate virtually all of its production, and has an average working interest of approximately 90 percent. On deeper, higher-risk exploration wells, the Company generally limits its working interest to 25-50 percent.

Industry Outlook

Overall, 2003 was an excellent year for the oil and natural gas industry. Average prices of both commodities were well ahead of prices received in 2002, creating a very positive environment for producers. West Texas Intermediate (WTI) oil averaged US$31.10 per barrel, 19 percent higher than in 2002, and ended the year at US$32.52 per barrel. Natural gas prices averaged US$5.49 per mmbtu on the NYMEX, 63.4 percent higher than in 2002, and ended the year at US$6.19 per mmbtu.

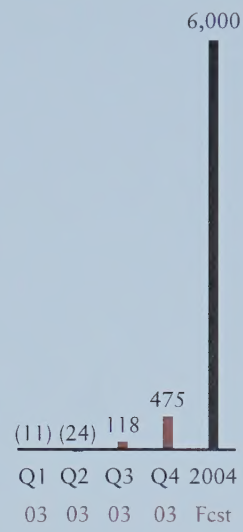
The high oil and natural gas prices experienced in late 2003 are expected to continue into 2004, based on supply and demand fundamentals. The world economy is showing signs of a full-fledged recovery and expansion. The resulting demand growth for oil products is being supplied largely by a disciplined OPEC adhering to a policy of tight market balance. This should result in high world oil prices through 2004, averaging up to US$30.00 per barrel. Continental natural gas prices are also expected to remain strong, as North American deliverability has essentially shifted into mild decline, regardless of the rate of natural gas drilling. Natural gas demand appears to be on a rebound associated with a strengthening U.S. economy. For this reason, most analysts are predicting an average 2004 natural gas price of US$5.00 per mmbtu.

The strong oil and natural gas prices of 2003 helped fuel very strong capital markets, particularly for the junior/emerging producers. Improved access to capital, coupled with strong cash flows, greatly increased activity in our industry. This in turn increased the costs associated with our business related to land, seismic, and drilling/production services. This high level of service costs is expected to continue into 2004.

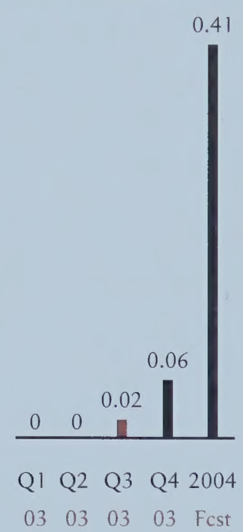
Corporate Governance

Hawk's management shares the concerns of regulators and investors regarding the integrity of financial and reserve information reported by the oil and natural gas industry. Accordingly, Hawk has put in place the necessary accounting and financial reporting systems and controls to ensure the Company maintains the highest level of accuracy and integrity in all its public disclosures. For this reason, Hawk utilizes large, respected accounting and reservoir evaluation firms, PricewaterhouseCoopers LLP and Gilbert Laustsen Jung Associates Ltd. and has three independent directors out of five total directors. Furthermore, Hawk's audit, compensation and reserve committees consist of independent directors.

Operating Cash Flow
($000s)



Operating Cash Flow
($/diluted share)



·Determination

We are determined to build a strong company with a rich opportunity base that delivers return on equity and return on capital. Our strategy is to deliver value by maintaining a strong balance sheet, with below-average F&D, operating and G&A costs.

From left:
Greg Templin, Manager, Exploration and
Dave Hudson, Manager, Engineering

2004 Outlook

Since Hawk's inception in June 2003, the Company has been highly successful in both drilling and acquisitions. We have prudently invested $13.1 million of the $17.25 million raised to date, creating a company which at December 31, 2003 was producing 750 boe per day and had proved reserves of 2.2 million boe. We have positioned Hawk with the undeveloped lands and seismic data needed to continue the momentum created in 2003.

The Company has a capital budget for 2004 of $12.5 million. This budget will fund the drilling of an anticipated 25 high working-interest wells. The majority of these wells are planned for Hawk's core areas at Retlaw, Edmonton, Endiang/Veteran and Southeast Saskatchewan. Hawk plans to invest up to 20 percent of its 2004 budget on deeper, higher-risk prospects in western Alberta.

Hawk is forecasting average 2004 production of 1,100 boe per day and an exit rate of 1,200 boe per day. These forecast rates do not include potential production from any exploration success from Hawk's 16 yet-to-be-drilled prospects. The Company is forecasting 2004 cash flow of $6 million, based on commodity price assumptions of US$29.00 per barrel of WTI crude oil and $5.85 per mcf of natural gas at AECO.

Hawk is well-positioned to take advantage of the many excellent opportunities available to grow the Company. We have a strong balance sheet, including $3.2 million in working capital. To date we have achieved a low cost structure with below-average F&D and operating costs. Having transitioned from a start-up producer in 2003, Hawk is continuing its fast-paced growth in 2004.

Acknowledgements

I take this opportunity to extend my deepest thanks to shareholders, directors, the Hawk team and other stakeholders for your support over the past year.

On behalf of the Board of Directors,

S. Fitzmaurice

Steve Fitzmaurice
President, Chief Executive Officer and Chairman
April 1, 2004

Review of Exploration and Operations

Operations Philosophy

Hawk Energy is managed by a small, enthusiastic, dedicated team of professionals with widely varied experience. These individuals worked initially at large resource companies and were active across much of Western Canada. The considerable skills and knowledge gained during this time were put to good use with the initiation and successful growth of Hawk Oil, a company previously managed and sold by Hawk Energy's executive team. This experience helped shape and clarify strategies employed by Hawk Energy today. A disciplined team with widely varied technical experience results in a flexible, fast-paced exploration and production effort.

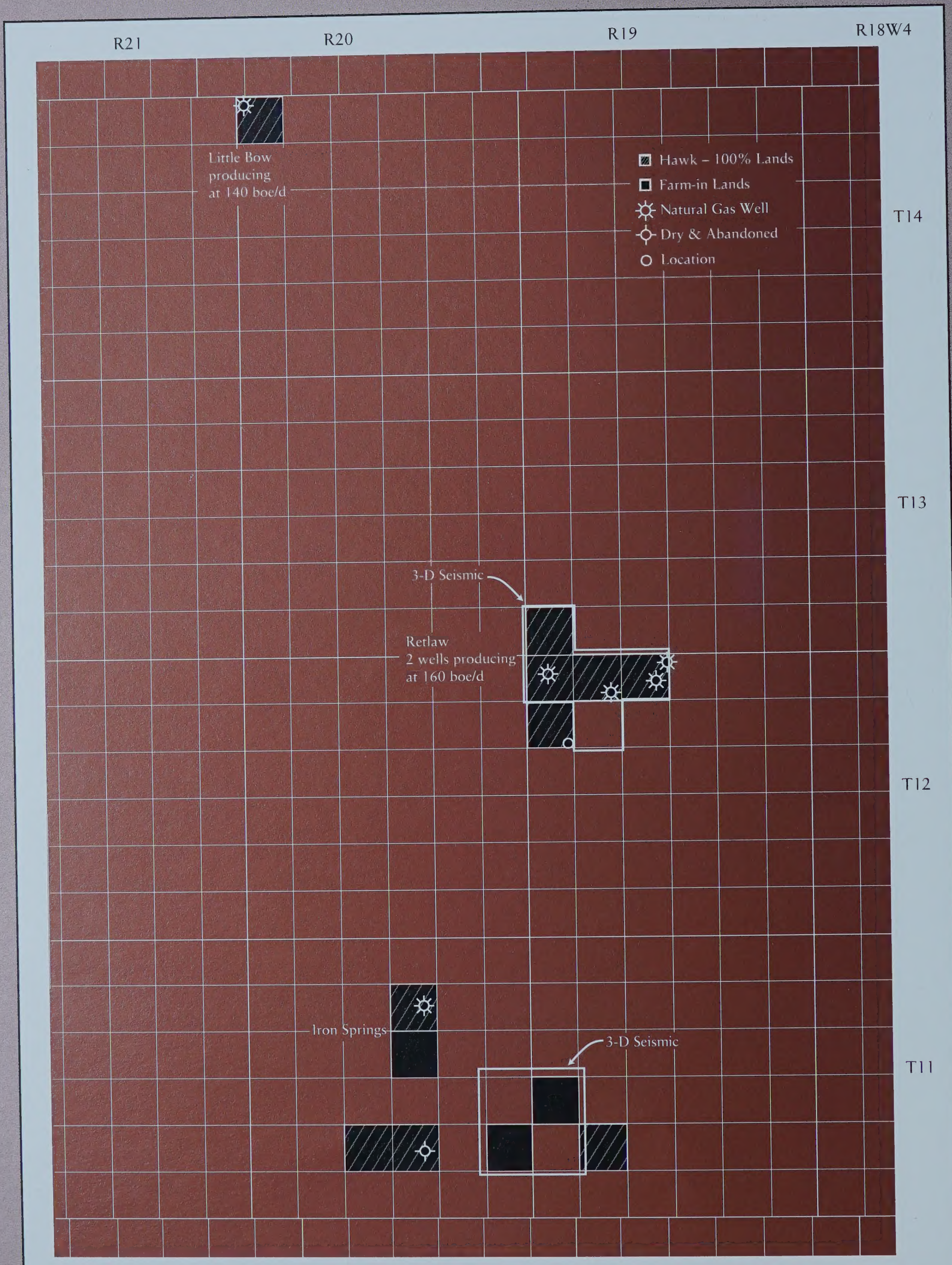
The Company believes in a balanced approach with respect to commodities and will attempt to maintain light oil/natural gas ratios that reflect this. This will be achieved through drilling a mix of exploration and development opportunities and prudently acquiring where possible. Hawk will continue to employ a strategy of patience and discipline in its approach to acquisitions, ensuring that any transaction delivers shareholder value.

The Company will pursue primarily low to moderate-risk prospects across regions that can be accessed easily and which are in close proximity to established core areas. Wells will be put on production quickly in order to generate near-term cash flow.

Hawk will also continue to nurture relationships with industry partners that favour acquisitions over drilling, often resulting in favourable exploration and development farm-in terms. Hawk's ability to rapidly execute projects, coupled with the present commodity price environment, allows the Company to drill a variety of prospects so long as criteria such as economic return, core region and infrastructure access are met.

The Company believes in operating all prospects at high working interests in order to maintain control over capital and operating costs and to maintain technical direction. This does not preclude taking lesser interests in certain high-risk, high-reward prospects.

Retlaw


R21
R20
R19
R18W4
T14
T13
T12
T11
Hawk – 100% Lands
Farm-in Lands
Natural Gas Well
Dry & Abandoned
Location
Little Bow
producing
at 140 boe/d
3-D Seismic
Retlaw
2 wells producing
at 160 boe/d
Iron Springs
3-D Seismic

Retlaw

The greater Retlaw area lies northeast of Lethbridge and encompasses lands from T10 to T14, R19 to R21, west of the fourth meridian. To date Hawk has acquired 6,080 (5,760 net) acres of land. An additional 1,600 acres is held under farm-in option. This area is accessible year-round and Hawk is continuing to expand operations.

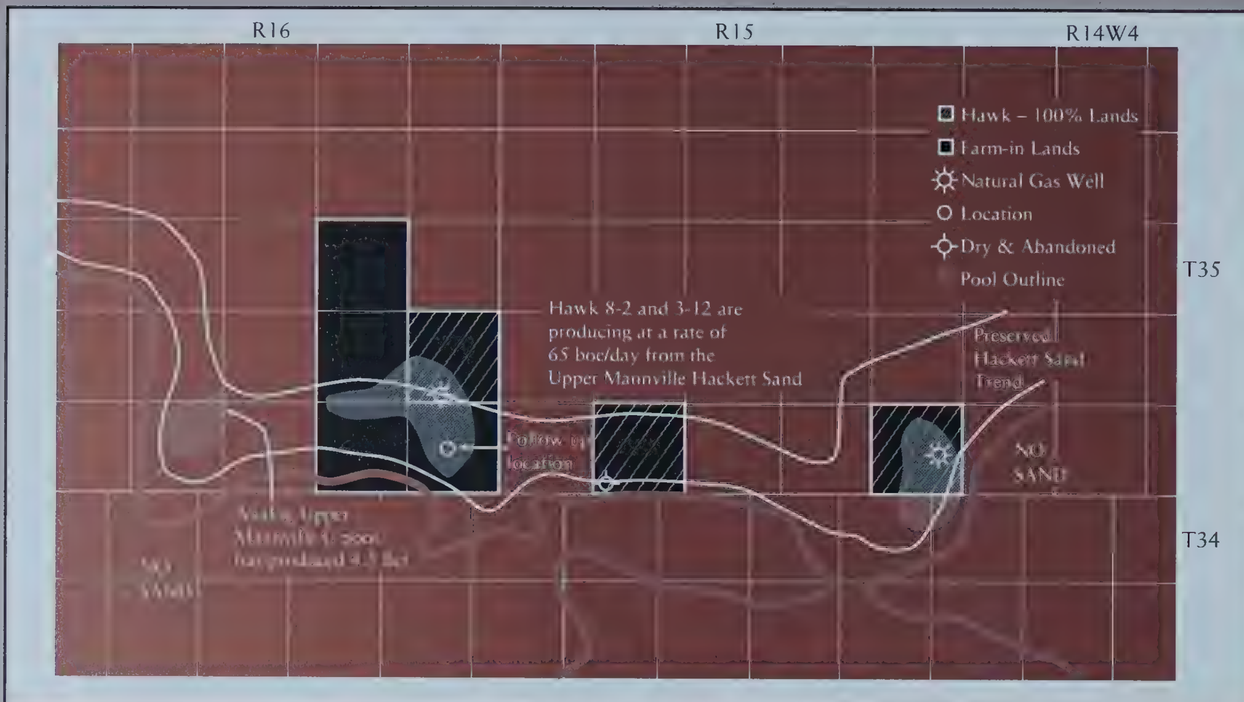
The Retlaw region is a true multi-zone area with production from the Mississippian Rundle Group at approximately 1,200 metres subsurface up to the Belly River Formation at 250 metres. Hawk is primarily pursuing multiple targets in the Mannville and the Bow Island Formations. These targets consist of structural highs in the Rundle Group carbonate and high-quality sandstone reservoirs in the overlying Sunburst/Glauconitic zones. Overlying the Mannville, the Bow Island Formation consists of a stacked series of linear, shoreface sands and shales. Natural gas is often trapped where these sands pinch out over structural highs. Between the Bow Island Formation and the surface, natural gas can occur in the Second White Specks, Medicine Hat, Milk River and Belly River Formations. These reservoirs are generally lower permeability and range from linear marine sand trends to fluvial channels in the Belly River.

By the end of 2003, Hawk had drilled three (3.0 net) successful natural gas wells at Retlaw. One well, completed in the Bow Island Formation, has been producing at a rate of 800 mcf per day for six months. The Company also shot a 13-square-kilometre 3-D seismic program which led to a number of drilling locations on another prospect. Two (2.0 net) wells were drilled and cased for natural gas in both the Sunburst and Bow Island Formations based on this seismic data. These wells have been tested and were put on production at a combined rate of 1.25 mmcf per day before the end of the first quarter of 2004.

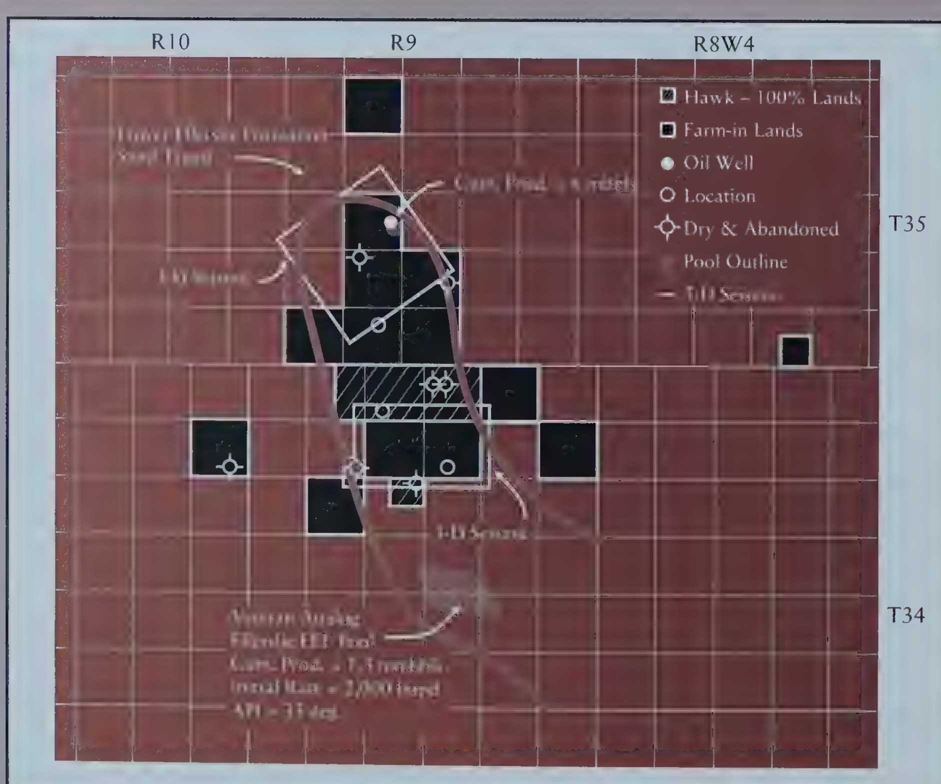
Field netbacks in this region (based only on one well) for 2003 were $2.83 per mcf ($16.98 per boe), while operating costs were $0.65 per mcf ($3.90 per boe).

Hawk is very pleased with results at Retlaw to date and is in the process of acquiring additional acreage in this core area. The Company will be shooting more 3-D seismic on lands already under control. Hawk has budgeted for the drilling of an additional five (5.0 net) wells in the Retlaw area for 2004.

Endiang



Veteran



Endiang/Veteran

This year-round accessible core area lies northeast of Drumheller, Alberta at T34/35, R8-16, west of the fourth meridian. At the close of 2003, Hawk controlled 4,480 acres of land at Endiang through a farm-in option. Three sections of land were subsequently earned with the drilling of two (2.0 net) successful natural gas wells and one well that was dry and abandoned.

At Endiang, the Company is targeting the Upper Mannville Hackett sand which is the pre-eminent producer in this area. This sand exists as erosional remnants of extensive braided stream deposits which were laid down during early Cretaceous time and are thought to have covered much of Alberta. These sands often have excellent reservoir quality and have produced in excess of 5 billion cubic feet of gas per well in close proximity to Hawk's land. Also prospective for natural gas at Endiang are the Viking and Belly River formations.

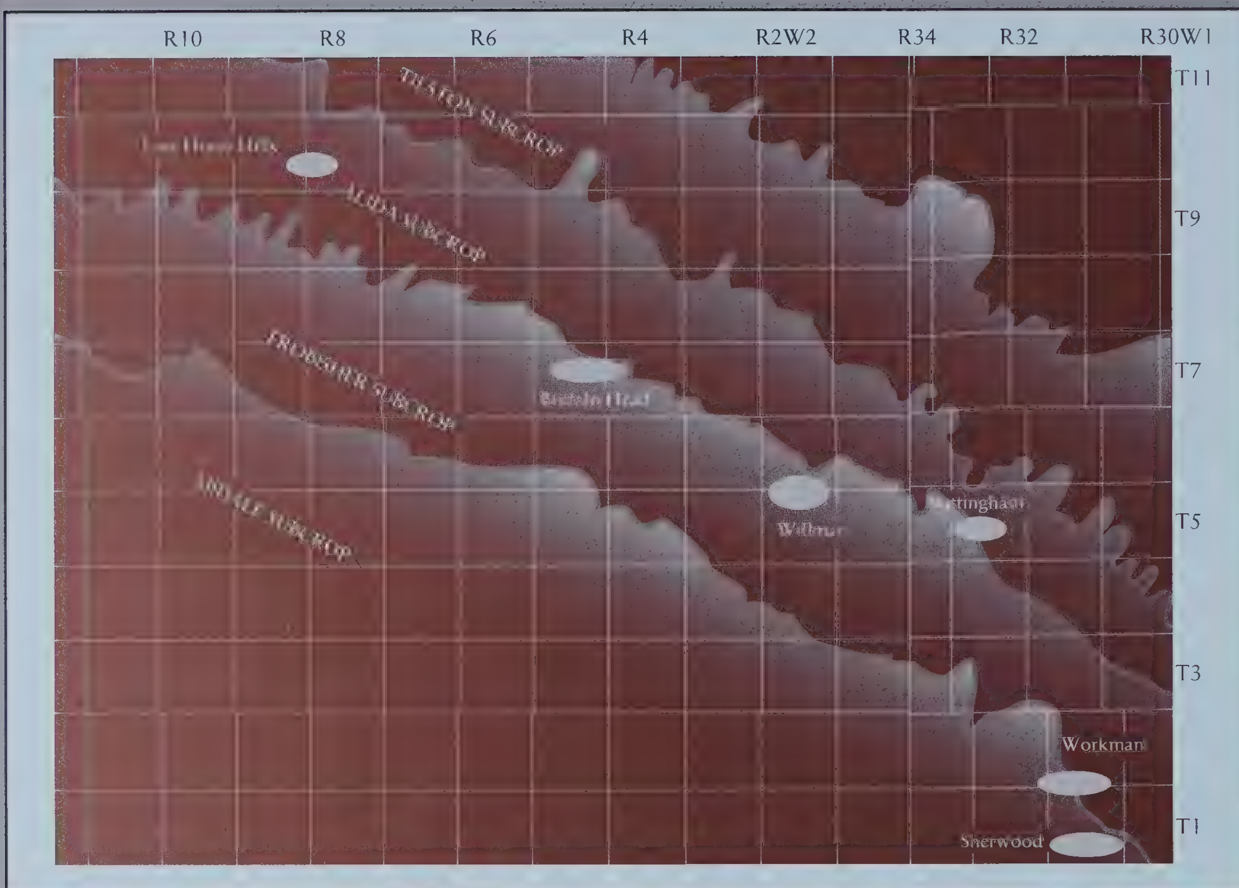
During late 2003, Hawk's two (2.0 net) successful natural gas wells on the farm-in block were tested and tied in. Both penetrated sands of inferior quality and needed to be fracture-stimulated. The wells are producing a combined 65 boe per day. The knowledge obtained from these wells has pointed the way to one or possibly two additional locations where higher rates are expected. Hawk continues to pursue this play into adjacent areas where considerable open land exists.

At Veteran, the Company controls 1,200 acres through a farm-in option. We followed this initial entry to the area with the shooting of a 3-D seismic survey and have added 9,040 acres of land through Crown sales and additional farm-ins. The Veteran area is also accessible throughout the year.

Hawk is in the early stages of developing an exciting light oil play. This prospect involves the definition of Lower Mannville, Ellerslie Formation sands. In the prospective area these sands were deposited adjacent to emergent uplands. They are two to six metres thick and highly permeable. Average initial production rates per well are typically 100 barrels per day with pool rates exceeding 1,000 barrels per day. The Company now controls 16 sections of land, has shot one 3-D seismic survey and has access to another large, adjacent survey. Drilling will commence as soon as weather and surface conditions allow in the second quarter of 2004.

The Company has budgeted a minimum of five (5.0 net) wells in the Endiang/Veteran area for 2004.

Southeast Saskatchewan



Following optimization of certain properties and the drilling of one horizontal well in Q1 2004, operating costs in Southeast Saskatchewan have been reduced to less than $9.00 per boe thus far.

Southeast Saskatchewan

When Hawk Energy was formed, one of its goals was to actively search for appropriate property or corporate acquisitions. This goal influenced the formation of the Company's technical personnel, resulting in a team that is adept at both exploration and acquisitions. Appropriate properties should complement Hawk's stated objectives including optimization or drilling potential as well as favourable acquisition metrics.

Hawk was fortunate to find such an acquisition candidate in Southeast Saskatchewan shortly after inception and was able to close a deal on November 12, 2003 (effective October 1). The transaction involved the purchase, at enviable metrics, of 380 barrels of oil per day with low declines and associated facilities. These properties have been producing for many years which allowed accurate decline analysis and cash flow forecasts. Technical familiarity with the acquired properties allowed Hawk to proceed quickly to evaluate and enhance existing production.

Along with the production, Hawk acquired 9,100 acres of land, including 3,000 acres of undeveloped land. The Company also acquired 17 sq. km of 3-D seismic and 15 km of 2-D seismic.

The majority of these pools contain light oil trapped in Mississippian-aged limestones at the pre-Cretaceous unconformity. The producing zones are the Alida, Kisbey and Frobisher beds of the Mission Canyon Formation. These zones are the premier producing zones in Southeast Saskatchewan, demonstrating high ultimate recovery factors, in part due to horizontal development. Some horizontal drilling opportunities have been identified and will be executed in 2004.

Field netbacks in this region for the last quarter of 2003 were $17.70 per boe and operating costs were $11.43 per boe. These numbers reflect production, costs and burdens from October 1, 2003, the effective date of the acquisition. Following optimization of certain properties and the drilling of one horizontal well in Q1 2004, operating costs in Southeast Saskatchewan have been reduced to less than $9.00 per boe thus far.

Hawk continues to systematically evaluate these acquired properties and will be conducting further optimization and drilling when warranted in 2004.

Other Drilling

In addition to these core areas Hawk has drilled six (4.8 net) wells in other areas where the Company uncovered attractive opportunities. At Marsden, Saskatchewan, Hawk drilled three (3.0 net) successful heavy oil wells on a low-risk prospect. These wells were producing in excess of 125 barrels per day at the close of 2003. Follow-up drilling has been identified through the shooting of a small 3-D seismic survey over the pool.

One (0.45 net) well was drilled on a low-risk natural gas prospect east of Lloydminster at Lashburn. This well encountered four, stacked, natural gas pay zones in the Mannville Formation. The well was tested in two of these zones and was put on production at 0.75 mmcf (335 mcf net) per day in December 2003.

Hawk also drilled one (0.35 net) successful natural gas well at Rivercourse, Alberta on a Colony zone prospect. The well was put on production in June at 250 mcf per day net. One (1.0 net) dual-zone prospect was successfully drilled at Nevis, Alberta in the third quarter of 2003. This well remains to be tied in as a result of infrastructure issues in the immediate area.

Other Exploration Areas

Edmonton

Hawk has been busy acquiring land, through farm-in and Crown sales, on a number of plays in the greater Edmonton area. At present, the Company controls in excess of 20 sections of land at working interests of 40-100 percent.

In this region, Hawk is targeting a variety of Mannville sands ranging from Ellerslie and Colony Formation channel/shoreface sands to the Glauconitic, Hoadley barrier bar sand. Hawk has purchased and evaluated considerable 2-D seismic in this area.

By the end of 2003, Hawk had drilled two (1.5 net) wells on two prospects. One well was dry and abandoned while the other discovered a new natural gas pool. This well (50 percent net) is on production at 1.0 mmcf per day at low drawdown and appears to hold promise for pool extension.

A minimum of seven (5.5 net) wells are budgeted for the coming year on a variety of additional plays in the Edmonton area.

Operations Statistical Review

2003 Operations Highlights

- Drilled 14 (12.3 net) wells, including 10 exploration wells. This resulted in 12 (10.3 net) producers for an overall success rate of 86 percent;
- Grew production from zero to 750 boe per day in the first nine months of operations
- Exited 2003 with a production mix of 70 percent oil and 30 percent natural gas;
- Increased proved reserves from 0 to 2.2 million boe at a finding and development cost of $6.72 per boe;
- Acquired 380 barrels per day of light, low decline oil production at $17,600 per producing barrel;
- Average corporate operating costs for oil production of $9.77 per barrel;
- Average corporate operating cost for natural gas production of $3.96 per boe ($0.66 per mcf);
- Acquired 33,425 (18,403 net) acres of land, of which 14,995 (7,731 net) were undeveloped; and
- Generated numerous prospects resulting in at least 15 drillable locations for the first half of 2004.

First Quarter 2004 Activity

The first quarter of 2004 has been very active for Hawk Energy. The Company drilled a total of nine (7.15 net) wells, casing seven (5.65 net) for production. This equates to a success ratio of 79 percent. Production exceeded 1,000 boe per day prior to spring break-up.

The Company drilled three (1.65 net) successful wells in the Edmonton area. Testing and subsequent tie-in of the wells is proceeding. As a result of the drilling, Hawk has identified additional locations.

Hawk also drilled four (3.5 net) wells in the greater Retlaw area. Two (2.0 net) were cased as potential dual-zone natural gas wells which were completed before the end of the first quarter. During the quarter, the Company shot a10 sq. km 3-D seismic survey on a new prospect in this area.

The Company continues to build land inventory on its play at Veteran where 16 contiguous sections of land are now either owned or optioned. Hawk has also acquired seismic and two (2.0 net) locations have been selected and will be drilled immediately after spring break-up.

In Southeast Saskatchewan, Hawk is proceeding with optimization of existing production. The Company is also evaluating properties with a view to divesting non-core assets and consolidating interests where appropriate. One (1.0 net) horizontal well was drilled and completed in the Nottingham area with initial oil production of 100 barrels per day. Plans are in place to begin the conservation of solution gas at Nottingham in the second quarter of 2004. The Company is very pleased with the production profile of its Southeast Saskatchewan acquisition. The Company has so far been able to mitigate natural declines with minimal capital outlay.

A new prospect area has been developed at Sibbald, Alberta which lies approximately 75 miles east of Hanna. Hawk drilled one (1.0 net) successful natural gas well during the first quarter which should come on production at approximately 65 boe per day in April. Additional land has been secured and Hawk will drill a second well when surface conditions allow. The Company has also developed a new prospect at Fenn where a well will be drilled during the second quarter on an exciting Nisku/Leduc light oil prospect. Hawk is reviewing additional seismic in this high-reward area.

Looking Forward

Hawk is proud of the results achieved over the first nine months of operations. The Company is seeing continued success in 2004. Hawk intends to employ the same growth strategies that have been successful in the past. Hawk is well-positioned financially to take advantage of drilling or acquisition opportunities as they are identified.

During 2004, the Company intends to drill a minimum of 25 high-working-interest wells across southern and central Alberta and Southeast Saskatchewan. These locations will be a mix of exploratory and development wells and will reflect the Company's stated growth strategies. Higher-risk, higher-reward prospects will account for 15-20 percent of Hawk's $12.5 million capital budget in 2004.

Hawk Energy has created a solid foundation in a very short time. The rapid growth experienced to date should continue given the many opportunities developed and the Company's healthy financial state. Hawk will also actively search for acquisitions that represent value and which complement the Company's assets.

The pace established during 2003 appears to be accelerating in the new year, with positive results to date. This year promises to be an exciting one for Hawk shareholders.

Undeveloped Land

At December 31, 2003 Hawk had a total of 33,425 (18,403 net) acres of lands under title, of which 14,995 (7,731 net) acres were undeveloped.

Sixty percent or 9,065 (4,105 net) acres of the undeveloped lands were located in Alberta while 40 percent or 5,930 (3,626 net) acres were located in southeast Saskatchewan.

Drilling

During 2003, Hawk participated in the drilling of 14 (12.3 net) wells, 71 percent of which were classified as exploration, resulting in 12 (10.3 net) producers for an overall success rate of 86 percent. Hawk operated 13 of the 14 wells.

Drilling Activity

Year ended December 31	2003 Gross	2003 Net
Oil	**3.0**	**3.0**
Natural gas	**9.0**	**7.3**
Dry	**2.0**	**2.0**
Total	**14.0**	**12.3**
Exploratory	**10.0**	**8.3**
Development	**4.0**	**4.0**
Average working interest (%)		**88**
Success rate (%)		**86**

2003 Drilling Activity by Area

Property	Wells Drilled
Retlaw, AB	**3**
Endiang, AB	**3**
Edmonton, AB	**3**
Lloydminster, AB/SK	**2**
Marsden, SK	**3**
Total	**14**

2003 Reserves

Hawk's reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. (GLJ) as at December 31, 2003. As Hawk did not commence operations until April 2003, comparatives for year-end 2002 are not available. The reserves have been evaluated and recommended for approval by Hawk's Reserve Evaluation Committee which is comprised entirely of independent directors. This Committee, as well as Hawk's Board of Directors, have approved the reserves evaluation as submitted.

GLJ utilized two price forecasts in determining the value of Hawk's reserves. The constant price forecast used the actual posted prices on December 31, 2003, and held those prices constant over the life of the reserves. The forecast prices are GLJ's standard price forecast effective April 1, 2004. The GLJ report is prepared in accordance with National Instrument 51-101 (NI 51-101), the new standards of disclosure for oil and natural gas activities as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003. NI 51-101 replaces National Policy 2-B (NP 2-B) and requires a higher degree of confidence in the assignment of oil and natural gas reserves. Under NI 51-101, proved reserves are defined as having a 90 percent probability that the actual reserves recovered will equal or exceed the assigned estimates, while probable reserves are defined as having a 50 percent probability that the actual reserves recovered will equal or exceed the assigned estimates.

Gross reserves are the Company's working interest share of reserves prior to deducting royalty burdens and do not include royalties received by the Company.. Net reserves are the Company's working interest share of reserves less all royalties owned by others (ie. Crown, freehold lessors and overriding royalty owners). Net reserves include all royalties received by the Company.

Summary of Oil and Natural Gas Reserves (Constant Prices and Costs)

	Light/Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)	Gross (mbbls)	Net (mbbls)
Proved								
Developed	1,037	899	265	229	2,174	1,628	2	1
Developed non-producing	–	–	–	–	2,462	1,677	18	11
Undeveloped	187	162	–	–	61	54	–	–
Total proved	1,224	1,061	265	229	4,697	3,359	20	12
Probable	266	232	71	61	1,068	780	3	2
Total proved plus probable	1,490	1,293	336	290	5,765	4,140	23	14

Net Present Values of Future Net Revenue (Constant Prices and Costs)

($000s)	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed	26,236	21,299	17,958	15,576	13,803	19,524	15,745	13,215	11,427	10,103
Developed non-producing	8,545	7,509	6,699	6,052	5,523	–	–	–	–	–
Undeveloped	3,883	3,280	2,840	2,507	2,247	–	–	–	–	–
Total proved	38,664	32,089	27,497	24,134	21,574	27,450	22,556	19,180	16,732	14,882
Probable	9,663	6,238	4,382	3,277	2,569	6,344	4,013	2,774	2,048	1,590
Total proved plus probable	48,327	38,327	31,879	27,412	24,143	33,794	26,569	21,954	18,780	16,472

Total Future Net Revenue Undiscounted (Constant Prices and Costs)

($000s) Reserves Category	Revenue	Royalties	Operating Costs	Well Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	81,120	14,569	24,067	1,323	2,498	38,664	11,214	27,450
Proved plus probable	99,133	17,623	29,358	1,323	2,502	48,327	14,533	33,794

Future Net Revenue by Production Group (Constant Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)
Proved	Light and medium crude oil (including solution gas and other by-products)	12,239
	Heavy oil (including solution gas and other by-products)	2,489
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	12,765
Proved plus probable	Light and medium crude oil (including solution gas and other by-products)	13,942
	Heavy oil (including solution gas and other by-products)	2,966
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	14,965

Summary of Oil and Natural Gas Reserves (Forecast Prices and Costs)

	Light/Medium Oil		Heavy Oil		Natural Gas*		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)	Gross (mbbls)	Net (mbbls)
Proved								
Developed producing	917	791	258	220	2,160	1,618	2	1
Developed non-producing	–	–	–	–	2,458	1,676	18	11
Undeveloped	180	156	–	–	58	52	–	–
Total proved	1,096	947	258	220	4,677	3,346	20	12
Probable	238	207	69	60	1,065	777	3	2
Total proved plus probable	1,334	1,154	327	280	5,742	4,123	23	14

** Estimates of reserves of natural gas may be reported separately for (i) associated and non-associated gas (combined) and (ii) solution gas.*

Net Present Values of Future Net Revenue (Forecast Prices and Costs)

($000s)	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed	19,363	16,687	14,712	13,212	12,040	14,577	12,473	10,930	9,768	8,865
Developed non-producing	7,678	6,830	6,159	5,617	5,171	–	–	–	–	–
Undeveloped	3,243	2,841	2,531	2,284	2,086	–	–	–	–	–
Total proved	30,284	26,359	23,402	21,114	19,296	21,488	18,533	16,326	14,632	13,298
Probable	7,235	4,969	3,618	2,765	2,199	4,870	3,262	2,326	1,749	1,372
Total proved plus probable	37,519	31,328	27,020	23,879	21,495	26,358	21,795	18,652	16,381	14,670

Total Future Net Revenue Undiscounted (Forecast Prices and Costs)

($000s) Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	69,757	12,907	22,325	1,346	2,895	30,284	8,796	21,488
Proved plus probable	85,330	15,557	27,894	1,346	3,014	37,519	11,161	26,358

Future Net Revenue by Production Group (Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)
Proved	Light and medium crude oil (including solution gas and other by-products)	9,406
	Heavy oil (including solution gas and other by-products)	2,325
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	11,683
Proved plus probable	Light and medium crude oil (including solution gas and other by-products)	10,763
	Heavy oil (including solution gas and other by-products)	2,729
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	13,555

Summary of Pricing and Inflation Rate Assumptions (Forecast Prices and Costs)

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29° API ($Cdn/bbl)	Natural Gas(1) AECO Price ($Cdn/MMBtu)	Exchange Rate(2) ($US/$Cdn)
Historical (3)						
2000	30.22	44.56	27.34	39.91	5.08	0.673
2001	25.97	39.40	16.94	31.56	6.21	0.646
2002	26.08	40.33	26.57	35.48	4.04	0.637
2003	**31.07**	**43.66**	**26.26**	**37.55**	**6.66**	**0.721**
Forecast						
2004	34.25	44.75	29.00	41.00	6.65	0.750
2005	29.00	37.75	25.00	33.75	5.55	0.750
2006	27.00	35.25	23.75	31.25	5.20	0.750
2007	25.00	32.50	21.00	28.50	5.00	0.750
2008	25.00	32.50	21.00	28.50	5.00	0.750

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.

(2) Inflation rates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

Reconciliation of Company Net Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved Plus Probable (mbbls)	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved Plus Probable (mbbls)	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved Plus Probable (mbbls)
April 1, 2003	–	–	–	–	–	–	–	–	–
Extensions	3	1	4	131	35	166	12	2	14
Improved recovery	–	–		–	–	–	–	–	–
Technical revisions	(9)	(7)	(16)	96	(100)	(4)	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions	981	213	1,194	–	125	125	–	–	–
Dispositions	–	–	–	–	–	–	–	–	–
Economic factors	–	–	–		–	–	–	–	–
Production	(28)	–	(28)	(7)	–	(7)	–	–	–
January 1, 2004	947	207	1,154	221	60	280	12	2	14

Note: The previous evaluation was prepared using Canadian National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Company previously applied a risk factor of 50 percent in reporting its probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50 percent) probable reserves reported by the Company.

The Company has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, etc.).

Reconciliation of Company Net Reserves by Principal Product Type (Forecast Prices and Costs)

	Conventional Natural Gas			BOE		
	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Net Probable (mmcf)	Net Proved (mboe)	Net Probable (mboe)	Net Proved Plus Probable (mboe)
April 1, 2003	135	35	170	23	6	28
Extensions	1,764	364	2,128	441	63	539
Improved recovery	–	–	–	–	–	–
Technical revisions	(154)	(62)	(216)	61	(117)	(55)
Discoveries	1,430	378	1,808	238	6	301
Acquisitions	252	62	314	1,023	223	1,371
Dispositions	–	–	–	–	–	–
Economic factors	–	–	–	–	–	
Production	(82)		(82)	(48)		(48)
January 1, 2004	3,346	777	4,123	1,738	398	2,136

Note: The previous evaluation was prepared using Canadian National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Company previously applied a risk factor of 50 percent in reporting its probable reserves. Under current N1 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50 percent) probable reserves reported by the Company.

The Company has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, etc.).

2003 Reserves Replacement

	2003
Production (mboe)	**48**
Net proved reserves additions (mboe)	**1,786**
Proved replacement ratio	**37**
Net proved plus probable reserves additions (mboe)	**2,184**
Proved plus probable replacement ratio	**46**

Recycle Ratio

The recycle ratio is a measure used to evaluate the effectiveness of a company's re-investment program. The ratio measures the efficiency of investing the proceeds from one barrel of oil equivalent of production into finding new barrels of oil equivalent of reserves. It accomplishes this by dividing the field netback per barrel of oil equivalent by that year's finding and development costs.

	2003
Operating netbacks ($/boe)	**16.34**
Proved finding and development costs ($/boe)	**6.72**
Proved recycle ratio	**2.4**
Proved plus probable finding and development costs ($/boe)	**5.48**
Proved plus probable recyle ratio	**3.0**

Capital Expenditures

($000s)	2003
Land and lease	362
Seismic	1,041
Drilling and completions	3,802
Property acquisitions	6,680
Property dispositions	–
Geological and geophysical salaries capitalized	193
Finding costs	12,078
Facilities	1,041
Corporate assets*	15
Finding and development costs	13,134

** Corporate assets include office improvements, equipment, computer hardware and software.*

Finding and Development Costs

($000s)	2003
Finding costs+	12,078
Development costs+	1,056
Future development costs	1,346
Total capital costs	14,480
Proved reserves	
Working interest reserve additions (mboe)*	2,154
Finding and development costs ($/boe)	6.72
Proved plus probable reserves	
Working interest reserve additions (mboe)*	2,642
Finding and development costs ($/boe)	5.48

+ Refer to net capital expenditures summary for details

**Refer to summary of oil and natural gas reserves table for details*

Reserve Life Index (Working Interest Reserves)

	2003
2003 Q4 production annualized (mboe)	170
Proved reserves (mboe)	2,154
Proved reserve life index (years)	12.7
Proved plus probable reserves (mboe)	2,641
Proved plus probable reserve life index (years)	15.5

Management's Discussion and Analysis

Management's discussion and analysis (MD&A) of the financial condition and the results of operations for Hawk Energy Corp. ("Hawk" or the "Company") should be read in conjunction with the audited financial statements and related notes for the period ended December 31, 2003.

Production information is commonly reported in units of barrel of oil equivalent or boe. For the purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. The conversion ratio of 6:1 is based on an energy equivalency conversion method, which is primarily applicable at the burner tip. It does not represent equivalent wellhead value for the individual products. Such disclosure of boe may be misleading, particularly if used in isolation.

All amounts are in Canadian dollars unless otherwise stated.

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Hawk's control, including: the impact of general economic conditions in Canada and the United States; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices; foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. Hawk's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking estimates will transpire or occur, or if any of them do so, what benefits, including the amounts of proceeds, that Hawk will derive therefrom.

The term "cash flow from operating activities", which is expressed before changes in non-cash working capital, is used by the Company to analyze operating performance, leverage and liquidity. The term "netback", which is calculated as the average unit sales price, less royalties and operating expenses, represents the cash margin for every boe sold. These terms do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles (GAAP) and, therefore, might not be comparable with the calculation of a similar measure for other companies.

Comparability of Prior Period Results

Hawk Energy was incorporated on January 16, 2003. As such there are no prior period results available for comparison.

Average Production

Period ended December 31, 2003	
Natural gas (mcf/d)	316
Oil and NGLs (bbls/d)	94
Total (boe/d)	147

Hawk added production in 2003 through both drilling and property acquisitions. The majority of these additions occurred in the fourth quarter of the year. The December 31, 2003 exit production rate was 750 boe per day.

Revenue

Period ended December 31, 2003	
Oil sales	$ 1,060,395
Per barrel	$ 29.99
Natural gas sales	571,910
Per mcf	$ 4.95
NGLs sales	2,217
Per barrel	$ 35.76
Interest income	135,211
Royalty income	21,505
Total revenue	$ 1,791,238

In 2003, the Company received $29.99 per barrel for its oil production. Hawk's 2003 total oil production was comprised of 51 percent light oil that originated from southeast Saskatchewan, where the Company received an average price of $36.45 per barrel, and 49 percent heavy oil that originated from the Marsden property, where the Company received an average price of $24.95 per barrel. Hawk's current oil production mix is 80 percent light and 20 percent heavy. The Company received $4.95 per mcf for its natural gas production. Approximately 94 percent of Hawk's natural gas was produced from Alberta properties while 6 percent was produced in southeast Saskatchewan, primarily as associated gas from the oil production. The Company received $35.76 per barrel for its NGLs production. Hawk produced 62 barrels of NGLs with its natural gas production from the Retlaw property.

Both oil and natural gas prices in 2003 were well ahead of prices paid in 2002. West Texas Intermediate (WTI) oil prices averaged US$31.10 per barrel, 19 percent higher than in 2002, and ended the year at US$32.52 per barrel. Similarly, NYMEX natural gas prices averaged US$5.49 per mmbtu, 63.4 percent greater than in 2002, and ended the year at US$6.19 per mmbtu.

The high oil and natural gas prices experienced at the end of 2003 are expected to continue in 2004. The basis for continued high prices in 2004 is basic supply and demand fundamentals. On the oil front, the world economy is showing signs of a full-

fledged recovery and expansion. The resulting growth in demand for oil products is being supplied mainly by an OPEC group that appears disciplined in maintaining a tight market balance. The result of this supply and demand situation is higher oil prices which many forecast will average US$30.00 per barrel in 2004.

Similarly, the natural gas price is expected to remain strong, as the North American natural gas supply has essentially shifted into a decline mode regardless of the level of natural gas drilling. Natural gas demand appears strong, spurred by higher activity associated with a strong U.S. economy. For this reason, most analysts are predicting an average natural gas price for 2004 of US$5.00 per mmbtu.

Hawk generated $135,211 in interest income from its cash-on-hand which was invested in bankers' acceptance notes. The Company also received $21,505 in royalty income from its McLaughlin property in which Hawk has a 7 percent gross overriding royalty before payout.

The Company had no hedging contracts during 2003.

Royalties

	Period ended December 31, 2003	Average Royalty Rate
Crown	**$ 236,376**	14%
Freehold	**68,867**	4%
Gross overriding	**49,934**	3%
ARTC	**(10,863)**	(1%)
Total	**$ 344,314**	20%

The Company's natural gas royalties, which are predominately Crown and attract the ARTC, averaged 20.6 percent. Hawk's oil royalties, which are comprised of Crown, freehold and gross overriding royalties, averaged 19.3 percent.

Operating Expenses

	Period ended December 31, 2003	Per Unit
Gross production expense	**$ 460,716**	$8.59/boe
Processing income	**(25,645)**	(0.48/boe)
Net production expense	**$ 435,071**	$8.11/boe

The Company's natural gas-related production expense was $0.66 per mcf or $3.96 per boe. Hawk's oil-related production expense was $9.77 per barrel. Specifically, oil-related expenses included: $6.74 per barrel for heavy oil production at Marsden and $13.58 per barrel for Southeast Saskatchewan light oil production. The Southeast Saskatchewan acquisition closed on November 12, 2003. Numerous one-time production expenses, such as the installation of flare stacks, were incurred in Southeast Saskatchewan during the last six weeks of 2003. Production expenses for Southeast Saskatchewan are expected to average $9.00 per barrel in 2004.

General and Administrative (G&A) Expenses

	Period ended December 31, 2003	Per Unit
Gross G&A expenses	**$ 609,253**	$11.36/boe
Capitalized overhead	**(193,124)**	(3.60/boe)
Net G&A expenses	**$ 416,129**	$7.76/boe

Hawk capitalized a portion of its G&A expense that was directly related to the geological and geophysical work performed to generate exploration prospects. Also included in the G&A expense was a number of corporate "start-up" costs. G&A expenses are expected to decrease on a per boe basis in 2004 as the "start-up" costs are eliminated and production is increased.

Depletion, Amortization and Site Restoration Costs

	Period ended December 31, 2003	Per Unit
Depletion	**$ 243,665**	$4.54/boe
Amortization	**61,983**	1.16/boe
Site restoration	**53,853**	1.00/boe
Total	**$ 359,501**	$6.70/boe

Hawk follows the full cost method of accounting. Accordingly, the costs of all wells, both successful and unsuccessful, are added to the Company's capital base and are depleted at the rate of production over the remaining proved reserves as determined by the GLJ report. The depletion rate for 2003 was 2.3 percent.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change occurs.

On June 9, 2003, the Canadian government substantially enacted federal income tax changes for the oil and natural gas sector that were outlined in its 2003 budget. Resource tax rates will decline from the current 27 percent to 21 percent by 2007. Concurrently, the 100 percent deductibility of the resource allowance will be phased out and Crown charges will become 100 percent deductible.

Hawk incurred current taxes of $37,726 in 2003. Included in the current taxes are $13,032 for the Large Corporations Tax and $24,694 for the Saskatchewan tax and resource surcharge.

The Company had the following income tax pools available at January 1, 2004:

	Annual Deduction Available	Tax Pools
Canadian Exploration Expense (CEE)	100%	$ 258,975
Canadian Development Expense (CDE)	30%	227,276
Canadian Oil and Gas Property Expense (COGPE)	10%	4,851,763
Undepreciated capital costs	25%	2,403,530
Share issue cost	100%	1,194,117
Non-capital losses carried forward	100%	401,659
Total		9,337,320
Less: tax pools renounced but not incurred		(4,791,401)
Total		$ 4,545,919

Net Income and Cash Flow from Operating Activities

Hawk generated cash flow from operating activities of $557,998 ($0.08 per diluted share). Net Income is derived from:

Period ended December 31, 2003	
Cash flow from operating activities	**$ 557,998**
Less: Stock-based compensation	**(77,764)**
Depletion and amortization	**(359,501)**
Future income taxes	**(133,486)**
Net loss	**$ (12,753)**

Cash Flow from Operations

	Period ended December 31, 2003	Per Unit ($/boe)
Petroleum and natural gas revenue	**$ 1,634,523**	$ 30.47
Interest income	**135,211**	2.52
Royalties, net of ARTC	**(322,810)**	(6.02)
Operating costs	**(435,071)**	(8.11)
General and administrative	**(416,129)**	(7.76)
Current taxes	**(37,726)**	(0.70)
Cash flow from operations	**$ 557,998**	$ 10.40

Field Netbacks

Period ended December 31, 2003	Oil and NGLs ($/bbl)	Natural Gas ($/mcf)	Combined ($/boe)
Sales price	$ 30.87	$ 4.96	$ 30.47
Royalties	(5.95)	(1.02)	(6.02)
Production expense	(9.77)	(0.66)	(8.11)
Field netback	$ 15.15	$ 3.28	$ 16.34

Capital Expenditures

Period ended December 31, 2003	
Land and lease retention	**$ 362,000**
Seismic	**1,041,000**
Drilling and completions	**3,802,000**
Property acquisitions	**6,680,000**
Geological and geophysical salaries capitalized	**193,000**
Facilities	**1,041,000**
Corporate assets*	**15,000**
Total	**$ 13,134,000**

**Corporate assets include office improvements, equipment, computer hardware and software.*

In 2003, Hawk incurred capital expenditures of $13,134,000. Approximately 50 percent of the total capital or $6,680,000 was used to purchase the Southeast Saskatchewan property while the balance of $6,440,000 was used to implement the Company's drilling program.

Liquidity and Capital Resources

On December 31, 2003, the Company had net debt of $50,000 and positive working capital of $3,181,569.

During 2003 the Company utilized the following capital resources:

Common share issuance	**$ 15,757,353**
Bank indebtedness	**50,000**
Cash flow	**557,998**
Total	**$ 16,365,351**

The Company issued 4,000,000 Class A shares prior to its initial public offering and 3,700,000 Class A and 832,500 Class B common shares pursuant to the initial public offering. Hawk also issued an additional 3,500,000 Class A shares on December 12, 2003 to finance the Company's Southeast Saskatchewan property acquisition.

The Class B shares are convertible at the option of the Company at any time after June 30, 2006 and before June 30, 2008 into Class A shares. The conversion is calculated by dividing $10 by the greater of $1 and the then-current market price of Class A shares. If conversion has not occurred by the close of business on June 30, 2008 the Class B shares become convertible at the option of the shareholder into Class A shares on the same basis. Effective August 1, 2008 all remaining Class B shares will be deemed to be converted into Class A shares on the same basis.

On December 19, 2003 the Company entered into a revolving, reducing demand credit facility agreement with a bank for $6,350,000 at an interest rate of prime plus 0.25 percent per year. Starting January 31, 2004 the amount of the facility available will reduce by $200,000 per month. On December 31, 2003 the Company had drawn $50,000 from this credit facility.

2004 Capital Budget

Hawk's Board of Directors approved a 2004 budget of $12.5 million that focuses primarily on opportunities in southern Alberta and Saskatchewan. This budget includes drilling 25 high-working-interest wells. The majority of these wells will be drilled in Hawk's core areas of Retlaw, West Edmonton, Central Alberta and Southeast Saskatchewan. At March 31, 2004, Hawk had drilled nine (7.5 net) wells. Hawk plans to spend approximately 20 percent of its 2004 budget on deeper, higher-risk prospects in western Alberta.

Contractual Obligations

Pursuant to the May 22, 2003 initial public offering prospectus, the Company has issued flow-through shares. Accordingly, Hawk is required to incur $9,250,000 qualifying flow-through expenditures. During 2003, Hawk incurred qualifying expenditures totalling $4,458,599. The Company is obligated to incur an additional $4,791,401 of qualifying expenditures in 2004.

The Company is also committed to annual lease payments under a rental agreement for office space as follows:

2004	$ 24,850
2005	18,638
Total	$ 43,488

Dividend Policy

Hawk pays no dividends, as all cash generated from operations is used to finance the Company's drilling and acquisition activities.

Quarterly Results

The following table summarizes certain quarterly financial information relating to the Company.

2003 Quarter Ended	December 31	September 30	June 30	March 31	Total
Revenue (net of royalty)	**$ 1,117,472**	$ 263,879	$ 65,573	–	$ 1,446,924
Cash flow	**475,015**	118,139	(24,406)	(10,750)	557,998
Net income	**(17,843)**	40,892	(25,052)	(10,750)	(12,753)
Per common share - basic	–	–	–	–	–
Per common share - diluted	–	–	–	–	–
Total assets	**$ 19,312,846**	$ 10,565,631	$ 9,692,031	–	$ 19,312,846
Total long-term liabilities	–	–	–	–	–

Quarter Ended June 30, 2003

Hawk completed its initial public offering on June 5, 2003 raising gross proceeds of $9.25 million. The Company produced 19 boe per day, which generated negative cash flow of $24,406 and a net loss of $25,052. Capital expenditures of $498,174 were incurred during the drilling of two (1.4 net) wells and on seismic programs.

Quarter Ended September 30, 2003

Hawk produced 99 boe per day, which generated positive cash flow of $118,139 and net income of $40,892. Capital expenditures of $2,259,405 were incurred during the drilling of seven (5.9 net) wells and on seismic and land acquisitions.

Quarter Ended December 31, 2003

Hawk entered into an agreement to purchase 380 boe per day of production in Southeast Saskatchewan for $6.7 million. This transaction closed on November 12, 2003. The Company also closed a $7 million private placement at a price of $2.00 per Class A share. Hawk produced an average of 465 boe per day, which generated positive cash flow of $475,015 and a net loss of $17,843. Capital expenditures of $10,376,203 were incurred to acquire the Southeast Saskatchewan property, to drill five (5.0 net) wells and on seismic and land acquisitions.

Stock Price and Trading Activity

	2nd Q	3rd Q	4th Q	2003 Total
Class A				
High	$ 1.25	$ 2.20	$ 2.85	**$ 2.85**
Low	1.25	1.70	2.10	**1.25**
Close	1.25	2.10	2.85	**2.85**
Volume	40,000	160,226	80,300	**280,526**
Class B				
High	$ 5.00	$ 5.00	$ 5.25	**$ 5.25**
Low	5.00	4.00	5.00	**4.00**
Close	5.00	5.00	5.10	**5.10**
Volume	1,000	9,150	16,750	**26,900**

Critical Accounting Policies

Hawk's accounting policies are described in note 2 to the financial statements.

Certain accounting policies are identified as critical accounting policies because they form an integral part of Hawk's financial position and also require management to make judgements and estimates based on conditions and assumptions that are inherently uncertain. These accounting policies could result in materially different results should the underlying assumptions or conditions change.

Management's assumptions are based on Hawk's historical experience, management's experience and other factors that, in management's opinion, are relevant and appropriate. Management's assumptions may change over time as further experience is gained or as operating conditions change.

Business Risks

The oil and natural gas industry is subject to numerous risks that can affect the amount of cash flow from operating activities and the ability to grow. These risks include but are not limited to:

- Fluctuations in commodity prices, exchange rates and interest rates;
- Government and regulatory risk in respect of royalty and income tax regimes;
- Operational risks that may affect the quality and recoverability of reserves;
- Geological risk associated with accessing and recovering new quantities of reserves;
- Transportation risk related to the ability to transport oil and natural gas to market; and
- Capital markets' risk and the ability to finance future growth.

Hawk strives to minimize these business risks by:

- Employing management and technical staff with extensive industry experience;
- Adhering to a strategy of exploring, developing, acquiring and optimizing high-quality, low-risk reserves in areas where we have technical and operational expertise;
- Developing a diversified, balanced asset portfolio that generally offers developed operational infrastructure, year-round access and close proximity to markets;
- Maintaining a low-cost structure to maximize cash flow and profitability;
- Maintaining prudent financial leverage and developing strong relationships with the investment community and capital providers;
- Adhering to strict guidelines and reporting requirements with respect to environmental, health and safety practices; and
- Maintaining an adequate level of property, casualty, comprehensive and directors' and officers' insurance coverage.

Changes in Accounting Policy

The following two changes in accounting policy will be implemented in 2004:

Asset Retirement Obligation (ARO)

The new Canadian Institute of Chartered Accountants (CICA) standard for Asset Retirement Obligations changes the method of accounting for certain site restoration costs. Under the new standard, the fair value of asset retirement obligations are recorded as liabilities on a discounted basis, when incurred. The value of the related assets is increased by the same amount as the liability and depreciated over the useful life of the asset. Over time the liability is adjusted for the change in present value of the liability or as a result of changes to either the timing or amount of the original estimate of undiscounted future cash flows.

Asset retirement obligation requires that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Such assumptions are inherently uncertain and subject to change over time due to factors such as historical experience, changes in environmental legislation or improved technologies. Changes in underlying assumptions, based on the above-noted factors, could have a material impact on Hawk's future financials results.

Hedging Relationships

CICA accounting guideline 13, "Hedging Relationships", is effective for fiscal periods beginning on or after July 1, 2003. This accounting guideline addresses the identification, designation, documentation and effectiveness of hedging relationships, for the purpose of applying hedge accounting. In addition, it establishes criteria for discontinuing the use of hedge accounting. Under accounting guideline 13, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective to continue accrual accounting for positions hedged with derivatives. Hawk did not engage in any hedging activities in 2003. During 2004, the Company will assess such strategies to minimize the price risk associated with the volatility of commodity prices.

Stock-based Compensation

In 2003, Hawk adopted CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". This change in accounting policy was adopted in 2003 which resulted in a non-cash charge of $77,764.

Full Cost Accounting

In 2003, the CICA issued accounting guideline 16, "Oil and Gas Accounting – Full Cost." This accounting guideline replaces accounting guideline 5, "Full Cost Accounting in the Oil and Gas Industry." The guideline alters the ceiling test calculation and is effective for fiscal years beginning on or after January 1, 2004. Hawk is currently assessing the impact of this standard on its financial statements.

Management's Report

The financial statements of Hawk Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgements made by management.

External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements.

S. Fitzmaurice

Steve Fitzmaurice
President, Chief Executive Officer and Chairman

M. Shaikh

M.H. (Mike) Shaikh
Chief Financial Officer

Calgary, Canada
March 26, 2004

Auditors' Report

To the Shareholders of Hawk Energy Corp.

We have audited the balance sheet of Hawk Energy Corp. as at December 31, 2003 and the statements of operations and deficit and cash flows for the period from January 16, 2003 to December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statements presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and the results of its operations and its cash flows for the period from January 16, 2003 to December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
March 26, 2004

December 31, 2003

Assets	
Current	
Cash	$ 4,670,531
Accounts receivable	1,693,876
Prepaid expenses	120,305
	6,484,712
Property, plant and equipment, net (Note 3)	12,828,134
	$ 19,312,846
Liabilities and Shareholders' Equity	
Current	
Bank indebtedness (Note 4)	$ 50,000
Accounts payable and accrued liabilities	3,215,417
Income taxes payable	37,726
	3,303,143
Future income taxes (Note 5)	3,125,624
Future site restoration	53,853
	6,482,620
Shareholders' equity (Note 6)	
Share capital	12,765,215
Contributed surplus	77,764
Deficit	(12,753)
	12,830,226
	$ 19,312,846

Commitments (Note 7)

See accompanying notes to financial statements

Approved on behalf of the Board:

Thomas Buchanan
Director

John Wright
Director

Statement of Operations and (Deficit)

For the Period January 16, 2003 to December 31, 2003

Revenue	
Petroleum and natural gas sales, net of royalties	$ 1,311,713
Interest income	135,211
	1,446,924
Expenses	
Operating	$ 435,071
General and administrative	416,129
Stock-based compensation	77,764
Depletion and amortization	359,501
	1,288,465
Income before income taxes	158,459
Provision for income taxes (Note 5)	
Current	(37,726)
Future	(133,486)
	(171,212)
Net loss, representing deficit, end of period	$ (12,753)
Loss per share, basic and diluted	$ –

See accompanying notes to financial statements

Statement of Cash Flows

For the Period January 16, 2003 to December 31, 2003

Cash provided by operating activities		
Net loss	$	(12,753)
Items not affecting cash:		
Stock-based compensation		77,764
Depletion and amortization		359,501
Future income taxes		133,486
Cash flow from operating activities		557,998
Changes in non-cash working capital		
Accounts receivable		(1,693,876)
Prepaid expenses		(120,305)
Accounts payable and accrued liabilities		565,834
Income taxes payable		37,726
		(1,210,621)
		(652,623)
Cash used in investing activities		
Additions of property, plant and equipment		(13,133,782)
Changes in non-cash working capital for investing activities		2,649,583
		(10,484,199)
Cash provided by financing activities		
Issuance of share capital		17,250,000
Share issue cost		(1,492,647)
		15,757,353
Increase in cash, being cash and cash equivalents, end of period	$	4,620,531
Supplementary information		
Interest paid	$	(590)
Income taxes paid	$	–
Cash consists of		
Cash	$	4,670,531
Bank indebtedness		(50,000)
	$	4,620,531

See accompanying notes to financial statements

Notes to the Financial Statements

For the period January 16, 2003 to December 31, 2003
(all amounts in Canadian currency)

1. Incorporation and operations

The Company was incorporated under the Business Corporations Act (Alberta) on January 16, 2003. The principal business of the Company is exploration, exploitation, development and production of oil and natural gas reserves. All activity is conducted in Western Canada and comprises a single business segment.

2. Accounting policies

Property, plant and equipment

Petroleum and natural gas (P&NG) properties and production equipment

The Company has early-adopted AcG 16 "Full Cost Accounting", whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized and charged against earnings as described below. Capitalized costs include lease acquisition costs, the costs of geological and geophysical activities, the costs of drilling both productive and non-productive wells, carrying charges of non-producing properties and overhead costs directly related to exploration and development activities.

Proceeds from the disposal of properties are applied as a reduction of the cost of the remaining assets, except when such a disposal would alter the rate of depletion by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depletion of oil and natural gas properties and production equipment is provided using the unit-of- production method which is based upon gross proved reserve volumes. For this purpose, natural gas volumes are converted to equivalent oil volumes based upon the relative energy content where six thousand cubic feet of gas equates to one barrel of oil.

Costs of acquisition and evaluation of unproved properties are initially excluded from the depletion calculation. The Company periodically reviews costs associated with unproved properties to determine whether they are likely to be recovered. When such costs are not likely to be recovered, or when proved reserves are found to be attributable to the properties, the values of these properties are moved to the depletion pool.

The Company places a limit on the aggregate carrying value of property, plant and equipment. Impairment is recognized if the carrying amount of the property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third-party quoted forward prices. Upon recognition of impairment, the Company would measure the amount of impairment by comparing the carrying amounts of the property, plant and equipment to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Company's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Company's future cash flows would be recorded as a permanent impairment.

Other property, plant and equipment

Other property, plant and equipment is recorded at cost and is comprised of furniture, fixtures and equipment. Amortization is provided thereon at a rate of 20 percent per annum on a declining balance basis.

Future site restoration costs

Estimated future site restoration costs are provided for over the life of the proved reserves on a unit-of-production basis. Costs, net of expected recoveries, are estimated by management in consultation with engineers based upon current legislation, costs, technology and industry standards. The annual provision is included in depletion and amortization expense and actual expenditures are charged to the accumulated provision account as incurred.

Joint ventures

Substantially all of the Company's petroleum and natural gas activities are conducted jointly with others and, accordingly, the accounts reflect only the Company's proportionate interest in such activities.

Income taxes

The liability method is used in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change occurs.

Flow-through shares

The Company will from time-to-time issue flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital will be reduced and a future tax liability will be recorded equal to the estimated amount of the future income tax liability of the Company as a result of the renunciations, when the renunciations are made.

Stock options

The Company has a stock option plan, which is described in Note 6. Consideration paid by directors, officers and key employees and consultants on the exercise of stock options is credited to share capital together with the amount previously recognized in contributed surplus.

Direct awards of stock and stock options to employees and non-employees are accounted for in accordance with the fair value method of accounting for stock-based compensation. The fair value of direct awards of stock is determined by reference to the quoted market price of the Company's stock and the fair value of stock options is determined using the Black-Scholes option pricing model.

Revenue recognition

Revenues from petroleum and natural gas sales are recognized when title passes from the Company to its customer.

Per share data

The Company utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding, in-the-money options are used to purchase common shares of the Company at their average market price for the period. Unrecognized stock-based compensation from current grants is treated as proceeds used to purchase common shares.

Measurement uncertainty

The amounts recorded for depletion and amortization of oil and natural gas properties and equipment and the provision for future site restoration and abandonment costs are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

3. Property, plant and equipment

	Cost	Accumulated Amortization	Net Book Value
Petroleum and natural gas properties	$ 13,119,095	$ 302,711	**$ 12,816,384**
Furniture and equipment	14,687	2,937	**11,750**
	$ 13,133,782	$ 305,648	**$ 12,828,134**

As at December 31, 2003, total future site restoration and abandonment costs are estimated to be $2,246,250.

The Company has capitalized $193,124 in general and administrative costs during the period ended December 31, 2003.

Unproved property costs of $1,074,200 have been deducted from costs subject to depletion and amortization for the period ended December 31, 2003.

4. Bank indebtedness

On December 19, 2003, the Company entered into a revolving reducing demand credit facility agreement with a bank for $6,350,000 at an interest rate of prime plus one-quarter percent per year. Starting January 31, 2004, the amount of the facility available will be reduced by $200,000 per month. This credit facility is collateralized by a general assignment of book debts and a $25,000,000 debenture with a floating charge over all assets of the Company and will be reviewed periodically.

5. Future income taxes

The liability for future income taxes on the Company's balance sheet is comprised of the following temporary differences:

Future income tax liabilities	
Property, plant and equipment	$ 3,750,293
Future income tax assets	
Share issue costs	(446,848)
Site restoration	(18,684)
Non-capital losses carried forward	(159,137)
	$ 3,125,624

The income tax provision differs from the expected amount computed by applying the Canadian combined federal and provincial income tax rate of 40.75 percent as follows:

Computed "expected" income tax expense	$ (64,572)
Add back:	
Stock-based compensation	(29,939)
Non-deductible Crown charges	(83,129)
Non-deductible meals and entertainment	(2,245)
Deduct:	
ARTC	4,190
Resource allowance	9,240
Change in tax rate	3,565
Other	29,404
	(133,486)
Large Corporations Tax and Saskatchewan tax	
Large Corporations Tax	(13,032)
Saskatchewan tax and resource surcharge	(24,694)
	$ (171,212)

At December 31, 2003, the Company has tax pools as follows:

Undepreciated capital cost	**$ 2,403,530**
Canadian exploration expense	**258,975**
Canadian development expense	**227,276**
Canadian oil and gas property expense	**4,851,763**
Share issue costs	**1,194,117**
Non-capital losses carried forward	**401,659**
	9,337,320
Less tax pools renounced but not incurred	**(4,791,401)**
	$ 4,545,919

6. Share capital

Authorized:

Unlimited Class A common voting shares

Unlimited Class B common voting shares

ssued:	Shares	Amount
Class A common shares		
For cash as initial private placement	4,000,000	**$ 1,000,000**
Issuance of flow-through shares	3,700,000	**925,000**
Share issuance	3,500,000	**7,000,000**
Share issue cost, net of tax effect	–	**(313,918)**
Tax effect on flow-through shares	–	**(356,125)**
Class A common shares	11,200,000	**8,254,957**
Class B common shares		
Issuance of flow-through shares	832,500	**8,325,000**
Share issue cost, net of tax effect	–	**(609,617)**
Tax effect on flow-through shares	–	**(3,205,125)**
Class B common shares	832,500	**4,510,258**
Balance, end of period		**$ 12,765,215**

The Company has issued to directors, officers and employees 3,965,000 Class A shares as initial private placement, as well as 424,000 Class A flow-through shares and 95,400 Class B flow-through shares pursuant to the public offering prospectus.

Pursuant to the Escrow Agreement dated May 22, 2003 among the Company, the Custodian and certain of the current shareholders including all of the directors and officers who hold Class A shares, 3,365,000 Class A shares that were issued for cash as initial private placement were held in escrow. Ten percent of such Class A shares have been released from escrow on receipt of notice from the TSX Venture Exchange confirming the listing of the Class A shares on the TSX Venture Exchange. The remaining 90 percent will be released from escrow in 15 percent tranches during consecutive six-month intervals over a 36-month period following receipt of the above notice. The above escrow release schedule is subject to acceleration in accordance with National Policy 46-201 – "Escrow for Initial Public Offerings" and the policies of the TSX Venture Exchange in the event that the Company subsequently meets certain listing requirements.

The Class B shares are convertible at the option of the Company at any time after June 30, 2006 and before June 30, 2008 into Class A shares. The conversion is calculated by dividing $10 by the greater of $1 and the then current market price of Class A shares. If conversion has not occurred by the close of business on June 30, 2008, the Class B shares become convertible at the option of the shareholder into Class A shares on the same basis. Effective August 1, 2008, all remaining Class B shares will be deemed to be converted into Class A shares on the same basis.

Pursuant to the May 22, 2003 public offering prospectus, the Company offered for sale a maximum of 9,250 units through a prospectus offering. Each $1,000 unit consisted of 400 Class A flow-through shares at $0.25 per share and 90 Class B flow-through shares at $10 per share. Consequently, the Company issued 3,700,000 flow-through Class A common shares and 832,500 Class B common shares and agreed to incur $9,250,000 in qualifying flow-through expenditures. Pursuant to the terms of flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital is reduced and a future income tax liability is recorded on renunciation of flow-through shares equal to the estimated amount of the future income tax liability of the Company as a result of the renunciations. During the period, the Company incurred qualifying expenditures totaling $4,458,599. The Company is obligated to incur an additional $4,791,401 of qualifying expenditures.

Stock options

The Company has a Stock Option Plan that is granted by the board of directors to directors, officers, employees of and consultants to the Company. Under the terms of the plan, the Company has reserved an amount of Class A shares for options equal to 10 percent of the issued and outstanding Class A shares. Options granted under the Plan will have an exercise price which is not less than the price allowed by regulatory authorities, will be non-transferable and will be exercisable for a period not to exceed five years. No one optionee is permitted to hold options entitling such optionee to purchase more than 5 percent of the issued and outstanding Class A shares.

On June 6, 2003, the Company granted 770,000 options to directors, officers, employees of and consultants to the Company at an exercise price of $0.35. The options will vest one-third on each of the first, second and third anniversaries of the date of grant, and will expire on June 6, 2008. No options were exercised during the period. The Company early-adopted amendments to CICA

Handbook Section 3870 "Stock-based compensation and other stock-based payments". As a result of adopting this policy, non-cash compensation expense of $77,764 was recognized which decreased net income by $77,764 and increased contributed surplus by $77,764 for the period ended December 31, 2003.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used for grants in 2003: risk-free interest rate 4 percent; estimated hold period of three years; expected volatility 150 percent; and zero dividend yield. The weighted average fair value of stock options granted during the period was $0.29 per option.

7. Commitments

As of December 31, 2003, the Company is committed to annual lease payments under a rental agreement for office space as follows:

2004	$ 24,850
2005	18,638
	$ 43,488

8. Per share data

Basic per share data for Class A and Class B shares is based upon the weighted average number of Class A shares and the weighted average number of Class B shares outstanding during the period. The deemed conversion of Class B shares into Class A shares was done using the December 31, 2003 trading price of $2.85, resulting in total weighted average number of Class A shares of 7,237,249. Diluted per share data is based upon the weighted average number of Class A and Class B shares outstanding during the period after giving effect to the exercise of the share options.

9. Financial instruments

The Company's financial instruments consist of accounts receivable, bank indebtedness and accounts payable and accrued liabilities. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments.

Shareholder Information

Directors

Steve Fitzmaurice, P.ENG.
President, Chief Executive Officer
and Chairman of the Board
Hawk Energy Corp.

Dave Bonnar, P. GEOL.
Vice President, Corporate Development
Hawk Energy Corp.

Greg Turnbull, LLB*+
Partner
McCarthy Tétrault LLP

John Wright, P.ENG., CFA*+#
President and Chief Executive Officer
Petrobank Energy and Resources Ltd.

Thomas Buchanan, CA*+#
Chief Executive Officer
Provident Energy Ltd.

Officers

Steve Fitzmaurice, P.ENG.
President and Chief Executive Officer

Erik DeWiel, P. LAND
Vice President, Land and Corporate Secretary

Randy Deobald, P. GEOL.
Vice President, Exploration

Dave Bonnar, P. GEOL.
Vice President, Corporate Development

M.H. (Mike) Shaikh, CA
Chief Financial Officer

** member of the Audit Committee*
+ member of the Reserves Committee
 # member of the Compensation Committee

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National Bank of Canada
Calgary, Alberta

Transfer Agent

Computershare Investor Services
Calgary, Alberta

Solicitors

McCarthy Tétrault LLP
Calgary, Alberta

Stock Exchange Listing

TSX Venture Exchange
Trading Symbols: HK.A & HK.B

Engineering Consultants

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Calgary, Alberta

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